Assessment of the Buyer-Side Mitigation Exemption Test for the Hudson Transmission Partners Project

by:

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November 6, 2012, revised January 16, 2014

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This report was revised January 16, 2014 to add new Section V on the NYISO's redetermination pursuant the Commission's November order on the HTP Project.

I. Introduction and Summary

The Commission's June 22, 2012 Order requires that NYISO's Market Monitoring Unit ("MMU") prepare a report to be posted concurrently with the results of any buyer-side mitigation ("BSM") determinations (also referred to as mitigation exemption tests or "MET") under the Post-Amendment Rules.[1] This report provides our review of the revised BSM determination for the Hudson Transmission Partners, LLC project ("HTP Project"). The HTP Project is a 660MW HVDC transmission project that will connect the PSE&G Bergen Substation in New Jersey, with Consolidated Edison Company's ("ConEd") West 49th Street Substation in New York City.

The NYISO conducted both Part A and Part B Tests of the BSM analysis for the HTP Project merchant controllable line (Queue position #206, Class Year 2008).[2] The examination of the HTP Project was performed concurrent with Class Year 2010. On December 22, 2011, the NYISO determined that the HTP Project was not exempt under either the Part A or Part B BSM exemption tests. NYISO retested the HTP Project in accordance with the June 22 Order.

The only revisions to the NYISO's 2011 test of the HTP Project were to the change the inflation rate applied to Annual Net CONE (from 2.15% to 1.7%), and to apply the default financing assumption from the Demand Curve reset process rather than the actual financing secured by HTP for the project. The latter change was made to be consistent with guidance on this issue provided by Commission in its Order in Docket No. EL11-50.[3] The NYISO again determined the HTP Project was not exempt under either the Part A or the Part B test, and was subject to an Offer Floor.

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1 *Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc.*, 139 FERC ¶ 61,244 (2012) (June 22 Order) at PP 3, 50. The NYISO filed tariff compliance revisions on August 7, 2012 (supplemented August 8, 2012) to identify this obligation in its tariffs. *See* Docket No. ER12-2414.

2 The buyer-side mitigation tests are set forth in Services Tariff § 23.4.5.7.2 *et. seq*.

3 *Astoria Generating Company, L.P., et al. v. New York Independent System Operator, Inc.*, 140 FERC ¶ 61,189 (2012)("September Order").

The following sections each review key aspects of the NYISO's application of the exemption test. Section II reviews and discusses Part A of the exemption test, which compares the forecasted ICAP price in the first year of the study period to the Default Offer Floor that is based on the default peaking resource. Section III reviews and discusses Part B of the exemption test, which compares forecasted ICAP prices for the first three years after the HTP Project is anticipated to enter to the HTP Project's Unit Net CONE.

II. Part A Test

The Part A test compares a forecast of ICAP prices for the first year of the Mitigation Study Period ("MSP") to the Default Offer Floor, which is 75 percent of Mitigation Net CONE ("MNC").[4] NYISO included all existing capacity and Examined Facilities for the 2009 and 2010 completed Class Years as price takers. For purposes of this analysis, Linden VFT was assumed not to sell because the price of capacity in the source zone in PJM was forecasted to be higher than the price in New York City.[5] These assumptions led to a forecasted ICAP Spot Market clearing price of $0.00/kW-month.

Although we believe that the NYISO complied with the Tariff requirements in performing the price forecast in this manner, we believe there is a substantive deficiency in this methodology. NYISO included two mothballed units in its forecast. The NYISO concluded that it was obligated under the Tariff to include such units in the price forecasts until such time as the owners file notices with the New York Public Service Commission to retire. We filed comments with the Commission on this issue recently arguing that it is reasonable and necessary to interpret the Tariff to exclude such resources from the price forecasts.[6] These resources total more than 600 MW of ICAP and the forecasted price would rise to roughly $40 per kW-year if they were excluded. This change, however, would not result in an exemption for the HTP Project under the Part A test.

Given the forecasted price of zero, NYISO chose to assume a minimum capacity price forecast of $1.00 per kW-month. This is immaterial because the Default Offer Floor based on a 1.7 percent escalation of the 2011 reference point is $133.62 per kW-year in UCAP terms. Hence, NYISO finds that the HTP Project is not exempt under the Part A test and we agree.

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4 *See* June 22 Order at P 7, n. 11 (explaining that "Mitigation Net CONE" is a new term that NYISO proposed which is still pending Commission review in Docket No. ER10-2371-000 and stating that it represents "the price equal to what the Commission defined as the 'net CONE' used to design the NYC demand curves").

5 This assumption did not utilize actual Linden VFT transaction data or infer possible transactions, and instead utilized a comparison on capacity market price forecasts.

6 See: *Request For Leave To Answer and Answer of the New York ISO's Market Monitoring Unit* in Docket No. ER12-360.

III. PART B TEST

The Part B test compares the three-year average ICAP forecast price to the HTP Project's Unit Net CONE for the Mitigation Study Period (*i.e.*, the first three years after the HTP Project's "Reasonably Anticipated Entry Date".)

A. PART B PRICE FORECAST

To conduct the price forecast for the Part B test, NYISO includes existing units as price-takers and all Examined Facilities in completed Class Years 2009 and 2010 (*i.e.*, projects that accepted their Project Cost Allocations). The Examined Facilities are assumed to be price-takers if they are exempt, or offered at their respective Offer Floor if they are not exempt. Linden VFT was not assumed to sell capacity during the Mitigation Study Period because the price of capacity in PJM (in PSEG North) exceeds the forecasted price in New York City. Under this methodology, the NYISO forecasts an average annual ICAP spot price of $54.56/kW-year.[7]

With regard to the Linden VFT assumption, NYISO used the PJM's price from its base residual auction ("BRA"), which is conducted three years in advance of the delivery year. The price from the BRA averaged $83.64/kW-year. We believe this is reasonable, although more recent Incremental Auctions have cleared at lower price levels. The BRA is a much more liquid auction given that virtually all of PJM's capacity needs are satisfied through the BRA. Alternatively, very little capacity trades through the Incremental Auction and the PJM capacity demand curve is generally not used to clear the Incremental Auction. Therefore, one can expect the Incremental Auction prices to be highly volatile and sensitive to capacity purchases by either Linden VFT or the HTP Project. See Section IV for a fuller discussion of this issue.

As described above, we believe that mothballed units and all other units that are not eligible to sell capacity in the NYISO capacity market should be excluded from the capacity price forecasts

7 As discussed above, the assumptions regarding the Linden VFT are not based on actual Linden VFT data or transactions.

for Part A and Part B of the MET. Doing so would raise the Part B price forecast to more than $80 per kW-year; however, this change would not alter the result of the Part B test.

B. HTP PROJECT'S UNIT NET CONE

The estimated ICAP price discussed in the prior sub-section is compared to a resource's Unit Net CONE in the Part B test. A resource's Unit Net Cone is calculated by subtracting its estimated energy and ancillary services net revenues from its cost of new entry. These two elements are discussed in this subsection.

1. Cost of New Entry

The HTP Project costs were reviewed by NYISO with the assistance of Sargent & Lundy, and were found to be reasonable and accurate. We reviewed these costs as well and found no evidence that they were misrepresented. NYISO excluded a small share of the HTP Project's total project costs corresponding to various studies, legal and permitting costs. These costs were deemed to be sunk by HTP prior to the decision to move forward with the project. We support the exclusion of such costs and find the NYISO's assumption reasonable. No additional development costs should be excluded as sunk, regardless of whether they occurred prior to the final buyer-side mitigation determination because such costs would most likely indicate that the developer committed to the project prior to the determination.

The NYISO made a significant change in its calculation of HTP Project's CONE regarding the financing assumptions for the HTP Project. The Commission provided guidance related to financing assumptions in the September Order. In the September Order, the Commission indicated that NYISO should have used the default financing assumptions it used in its Demand Curve reset process in performing the MET for the Astoria Energy II project ("AEII"). The purpose of using the default financing assumptions is to eliminate the effects of any indirect subsidy a project may enjoy in the form of unusually favorable financing by virtue of developer's contract to build the facility. The RFP process that resulted in the HTP contract was very similar to the RFP that resulted in the AEII contract and was conducted by the same buyer, the New York Power Authority. Hence, we conclude that the use of the default financing assumptions is consistent with FERC's policy articulated in the September Order.

2. Net Revenue

The estimation of forecasted energy and ancillary services net revenue is a key component of the MET, since a new project developer expects to recoup a large share of its investment from future energy and ancillary services revenues. Estimating the net revenue of a new generator is a complex endeavor, requiring the use of models to estimate future LBMPs at which the new generator would sell its output. In the case of the HTP Project, the analysis is further complicated because the cost of energy depends on LMPs in a neighboring control area rather than the variable production costs of a new generator.

We carefully reviewed the assumptions used by the NYISO in estimating the net revenues for the HTP Project to determine whether they were reasonable and consistent with the Services Tariff. Overall, we conclude that the NYISO used assumptions that were both reasonable and tariff compliant. We also discuss potential alternative assumptions, concluding that results of the MET for the HTP Project would not be affected by reasonable improvements in assumptions.

Description of Methodology

As in the Demand Curve reset process, the NYISO used data from November 2006 to October 2009 to forecast net energy revenues in the first three years of operation of the new HTP Project. The following formula was used to calculate Estimated Net Revenue:

$$Estimated\ Net\ Revenue = \sum_h \{\text{max of } (\$0, Estimated\ DA\ Price\ Spread - Export\ Fee)\} \times Scaling\ Factor \times 660\ MW$$

In essence, the equation above calculates the maximum potential net revenue that could be earned in each hour (after deducting the applicable export fee) by scheduling a 1 MW export from PJM and scheduling a 1 MW import to the NYISO based on day-ahead clearing prices in each market. This is summed across the three year Mitigation Study Period, multiplied by the 660 MW capability of the line and a Scaling Factor. The Scaling Factor represents the expected share of the maximum potential net revenue that one can reasonably expect the scheduling of the HTP Project to capture. The full potential net revenue cannot reasonably be captured because the transactions must be scheduled based on forecasted prices in PJM and New York City well in advance of the markets clearing and producing actual prices. These actual market prices are highly volatile, making it difficult to predict the direction in which to schedule profitably. Forecasting errors would tend to reduce HTP's ability to capture the full potential net revenue. If a Scaling Factor were not employed by NYISO, the net revenue estimate would assume perfect arbitrage between PJM and the NYISO in the day-ahead market, which is not reasonable.

NYISO assumed an average export fee of $1.17/MWh, which is based on PJM's charge to exports for non-firm transmission service. The estimated day-ahead price spread in each hour of the first three years of operation is calculated as equal to the historic day-ahead price spread in an hour during the period from November 2006 to October 2009, based on data in the NERA model for the 2011/2013 Demand Curve reset, plus an adjustment for the expected LBMP effect from having a higher reserve margin in New York City in the future period. The historic day-ahead price spread in each hour is equal to the LBMP at Zone J minus the LMP at the Bergen generator bus, which is in PSEG-North and determined by NYISO to be the closest electrical point to the HTP Project's interconnection in PJM.

The relationship between the expected LBMPs and the New York City reserve margin is estimated based on the model used in the 2011/2013 Demand Curve reset process. The forecasted change in the reserve margin (expressed as a percentage of the New York City capacity requirement) in each hour was based on the actual reserve margin in each hour during the historic period and the forecasted reserve margin averaged over the HTP Project's Mitigation Study Period (*e.g.*, the forecast reserve margin in a particular hour on a particular day of May 2013 minus the actual reserve margin in the same hour on the same day of May 2006).

The Scaling Factor was estimated based on actual confidential historic market data to determine the net revenues that could theoretically be earned from perfect arbitrage between PJM and the NYISO. The historic data provides a reasonable basis for projecting the likely performance of the HTP Project. This analysis also enabled the NYISO to factor in the effect of comparable scheduling rules and restrictions to which the HTP Project can be expected to be subject.

The Scaling Factor was calculated as follows:

$$Scaling\ Factor =$$

$$= \frac{\begin{Bmatrix} \sum_h\{(DA\ Price\ Spread - Export\ Fee) \times DA\ Sch\ MW\} \\ + \sum_h\{\ (RT\ Price\ Spread - I_{MW}) \times (RT\ Sch\ MW - DA\ Sch\ MW)\} \end{Bmatrix}}{\sum_h\{max\ of\ (\$0, DA\ Price\ Spread - Export\ Fee) \times Max\ Capability\ MW\}}$$

$$I_{MW} = \begin{cases} Export\ Fee, & if\ RT\ Sch\ MW < DA\ Sch\ MW \\ -Export\ Fee, & otherwise \end{cases}$$

The price spread measures the difference between the NYISO and PJM proxy LBMPs. The day-ahead and real-time schedules are based on the actual historic interchange. The day-ahead optimal schedule is set to the full line capability whenever the day-ahead price spread was greater than the export fee and to 0 MW whenever the day-ahead price spread was less than or equal to the export fee.

The methods and assumptions used to estimate net revenues for the HTP Project were generally consistent with those used in the Demand Curve reset process. In consideration of the particular characteristics of the HTP Project, the NYISO adapted the methodology in a manner that was reasonable and consistent with the NYISO's Tariff.

Estimated Price Spreads between PJM and New York City

The Estimated Net Revenues were affected by several key assumptions that we discuss in this section. Specifically, the NYISO:

- Used the LBMP for Zone J rather than where the HTP Project will interconnect on the 345kV system;
- Used the historic LMPs at the Bergen generator bus in PJM without adjusting for future changes in the reserve margin of PSEG-North as it did for future changes in the reserve margin of New York City;

- Assumed transaction costs for exports from PJM to the NYISO based on the charges for non-firm transmission service;
- Assumed a New York City reserve margin of 26 percent, which fully counted the UDRs from the HTP Project, the Linden VFT, and several internal generators that had provided a notice of intent to mothball.

Some of these assumptions could have been improved, but we do not find that any of these assumptions would likely have changed the results of the Part B test. Improvements in the first three assumptions would decrease the Estimated Net Revenue for the HTP Project, while improvements in the fourth assumption would increase the Estimated Net Revenue.

1. *Using the LBMP for Zone J rather than where the HTP Project will interconnect on the 345kV system;*

The NYISO used the Zone J LBMP because the net revenue model developed in the 2011/2013 Demand Curve reset process provided estimates of how changes in the New York City reserve margin would affect LBMPs for Zone J, not specific nodes within Zone J. The NYISO applied an adjustment to these estimates to account for lower revenues received on the 345kV system relative to the Zone J LBMP. Ideally, a net revenue model could be developed specifically for predicting the LBMPs at the HTP Project bus or for predicting the price spreads between PJM and the NYISO across the HTP Project, but this would have required significant resources. The LBMP is generally 2 to 3 percent higher at Zone J than at the area where the HTP facility will interconnect. Consequently, using the Zone J LBMP led to slightly higher estimated price spreads and net revenues.

2. *Using historic LMPs at the Bergen generator bus in PJM without adjusting for future changes in the reserve margin of PSEG-North;*

The NYISO used the historic LMPs at the Bergen generator bus without adjusting for expected changes in the reserve margin of PSEG-North. Ideally, a net revenue model could be developed specifically for predicting the LMPs at this location, but this also would have required significant time and effort. There are no obvious alternatives to this assumption that would be relatively simple to implement. Nonetheless, it is appropriate to consider how this assumption might have affected the overall result.

From the historic period (November 2006 to October 2009) to the initial three years of operation for the HTP Project (May 2013 to April 2016), there have been significant changes in supply and demand in PSEG-North (including the addition of the HTP Project) that would lead to higher LMPs in PSEG-North. These higher LMPs would tend to reduce net revenues for the HTP Project.

3. *Assuming transaction costs for exports from PJM to the NYISO based on the charges for non-firm transmission service;*

The NYISO assumed imports to New York City across the HTP Project would generally pay PJM for non-firm transmission service. Exporters from PJM pay some additional uplift charges for Operating Reserve Credits, which vary from hour-to-hour and depend on how much is scheduled in the day-ahead versus the real-time market. It would be an improvement to incorporate these uplift charges in the net revenue estimates, which would tend to reduce the estimated net revenues for the HTP Project.

4. *Assuming full imports over Linden VFT and the HTP Project, and operation by mothballed units in the reserve margin used to estimate future day-ahead prices in New York City.*

By including all of the supply listed above, the NYISO estimated a 26 percent reserve margin, which it used in the calculation of the expected day-ahead price spread described above. Excluding only mothballed units from this analysis would have raised the estimated day-ahead prices for New York City by more than 5 percent. Hence, New York City prices were likely understated, reducing estimated net revenues.

Conclusion

Although improving the reserve margin assumption would increase the estimated net revenues for the HTP Project, this increase would be largely offset by improvements to the first three assumptions listed above. Hence, we conclude that the overall results of the analysis were reasonable and that, while it may be worthwhile to improve the methodology for future METs, such improvements would be unlikely to affect the MET results for the HTP Project.

IV. Factors Affecting Both the Part A and Part B Tests

A. Class Year

The mitigation exemption test for the HTP Project was performed with the same Mitigation Study Period as the completed Class Year 2010, although the project was in Class Year 2008. Performing the analysis for the HTP Project with projects in the completed Class Year 2010 was consistent with the Commission's February 2011 order in Docket No. ER10-3043.[8] The Commission adopted the BSM rules in this docket and made one exception for the HTP Project. The Commission directed the NYISO to evaluate the HTP Project "under the existing Reasonably Anticipated Entry Date Rule." HTP informed the Commission that its actual project start date was 2013.

In compliance with the February 2011 Order, NYISO used the entry date of the Summer Capability Period (May 2013). Consistent with the BSM Rules, the NYISO examined the HTP Project concurrent with other "Examined Facilities" in Class Year 2010 that shared the same Starting Capability Period.

NYISO believes that this is appropriate and consistent with the requirements of the Tariff and the Commission's February 2011 Order. We do not disagree with this finding. Substantively, we believe that this is appropriate because the commitment to move forward with the project likely did not occur until 2011 and the project is not scheduled to be operational until 2013.

B. Assumed Capacity Cost in PJM

The NYISO's assumptions regarding the cost of exporting capacity from PJM are critical to the outcome of the MET for the HTP Project in several ways:

- The HTP Project's Unit Net CONE is partly based on the cost of exporting capacity from PJM.

[8] *See New York Independent System Operator, Inc.*, 134 FERC ¶ 61,083 at P 25 (2011).

- Second, the cost of exporting capacity from PJM determines the extent to which the Linden VFT is assumed to be used to sell capacity into New York City in the price forecasts for the Part A and Part B tests.
- If it is not mitigated, the HTP Project's Offer Floor can be affected by this assumption since it would be set at the lower of the Unit Net CONE and the Default Offer Floor.

Hence, we carefully reviewed the assumptions and calculations used by the NYISO to determine the cost of exporting capacity from PJM. Overall, we find that the NYISO's assumptions were reasonable and compliant with the MST. Accordingly, we support the overall results of the NYISO's determination.

NYISO estimated that the average cost of exporting capacity from PJM across the HTP Project would be $83.64 per kW-year for the three years from May 2013 to April 2016. This estimate was based on the results of the Base Residual Auctions ("BRA"), which are held three years before the delivery period and are the primary market for the sale of capacity in PJM.

Although the auction is conducted three years in advance, we find that the NYISO's approach of using the clearing prices from the BRA is generally reasonable for the following reasons.

- The BRA is extremely liquid. Almost all capacity that is traded in PJM occurs through the BRA.
- All supply must be offered in the BRA. Suppliers that do not wish to offer in the BRA in order to export capacity must have a bilateral contract to do so. Therefore, one cannot reasonably expect capacity to be available after the BRA is conducted.
- The Incremental Auctions that are conducted much closer to the delivery timeframe in NYISO are generally illiquid and lack sufficient supply to support capacity exports over the Controllable Line facilities that can import capacity into New York City. For example, the supply offered in the 2012/2013 and 2013/2014 Incremental Auctions ranged from 147 MW to 226 MW, far less than the amount of capacity that HTP would need to purchase.

- Given the lack of liquidity in the Incremental Auction, attempts to purchase substantial quantities of capacity by HTP in that auction to support exports to New York City would likely result in sharply higher prices.

Although HTP has argued that the BRA prices may overstate the cost of procuring capacity in PJM, we believe the NYISO's assumption may understate the capacity cost because it does not include the price effects in PJM of the HTP Project's exports to NYISO. Estimating this price effect is not important in this case because it would not change the results of the MET.

V. ADDENDUM FOLLOWING NOVEMBER 2013 ORDER

A. BACKGROUND ON JANUARY 2014 REDETERMINATION

In November 2013, the Commission issued another order requiring the NYISO to retest the HTP project using the actual financing secured by the developer.[9] The original version of this report was issued on November 6, 2012, concurrent with the NYISO's first revised determination. A revised version of this report is being issued on January 16, 2014, concurrent with the NYISO's second revised determination. This Section describes the NYISO's modifications to the prior test that were made to conform to the November 2013 order.

B. MODIFIED COST OF CAPITAL

Background

In 2006, the HTP project was selected in a New York Power Authority ("NYPA") RFP for energy and capacity.[10] Subsequently, the developer was able to obtain financing for the HTP project on terms more attractive than were assumed for the ICAP Demand Curve unit in the evaluation that set the Demand Curves for 2011/12 to 2013/14.

In December 2011, the NYISO issued a BSM determination for the HTP project after the close of the 2009 and 2010 Class Years. The December 2011 determination was performed using the actual financing terms that were secured for the HTP project, resulting in a lower assumed weighted-average cost of capital and a lower annualized cost of new entry (than if the financing terms of the Demand Curve unit had been used).

In September 2012, the Commission found that the AEII project (which had been selected pursuant to a similar NYPA RFP for energy and capacity) had received low-cost financing partly as a result of "irregular or anomalous" advantages conferred by its contract with NYPA. The

9 *Hudson Transmission Partners, LLC v. New York Independent System Operator, Inc.*, 145 FERC ¶ 61,156, at P 112.

10 *Hudson Transmission Partners, LLC*, 135 FERC ¶ 61,104.

Commission deemed the NYPA contract with the AEII project to be based on an unduly discriminatory RFP process because the RFP excluded existing generating capacity from submitting proposals. Consequently, the Commission ordered the NYISO to issue a new BSM determination for the AEII project not using the actual financing costs. Instead, the Commission directed the NYISO to use a proxy value based on the financing costs of the Demand Curve unit.[11]

In November 2012, the NYISO issued a revised BSM determination for the HTP project using the generic financing costs of the Demand Curve unit. This was done because the HTP project had received attractive financing terms after signing a contract with NYPA that resulted from an RFP process that appeared to be unduly discriminatory by the standard the Commission had applied in its Order on the AEII project determination. This revision did not alter the outcome of the BSM determination that the HTP project be mitigated (*i.e.* subject to an Offer Floor.)

In November 2013, the Commission ordered that—despite the similarities between the NYPA RFP processes that led NYPA to contract with the AEII and HTP projects—the RFP pursuant to which the HTP project was selected did not have a "discriminatory effect." The Commission's ruling was because existing generators in New York City were already prevented from engaging in long-term contracts by a Commission approved mitigation measure. Thus, the Commission concluded that the attractive financing terms received by the HTP project should be used and that the NYISO should re-issue a determination based on the actual financing terms.[12]

January 2014 Redetermination

In accordance with the November 2013 Order, the NYISO revised the BSM determination for the HTP project using its actual financing terms. Specifically, the cost of debt, the debt-to-equity ratio, and the debt amortization assumptions were based on the terms of actual contracts between

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11 *Astoria Generating Company L.P v. New York Indep. Sys. Operator, Inc.*, 140 FERC ¶ 61,189, at P 135.

12 *Hudson Transmission Partners, LLC v. New York Independent System Operator, Inc.*, 145 FERC ¶ 61,156 ("November 2013 Order"), at P 112.

the HTP project and its creditors. Since the HTP project is not publicly-traded, the Capital Asset Pricing Model ("CAPM") could not be used to evaluate the reasonableness of the developer's asserted cost of equity. However, the developer's asserted cost of equity was deemed reasonable by the NYISO and its consultants.

The specific values used for the cost of debt, the debt-to-equity ratio, the debt amortization, and cost of equity assumptions for the HTP project are confidential. The NYISO assumed a 40-year useful life, which is ten years longer than the assumed useful life of the Demand Curve unit in the evaluation that set the Demand Curves for 2011/12 to 2013/14. The NYISO and its consultants determined that a transmission line is likely to remain in service longer than a generator. The NYISO's modifications to these parameters were made consistent with the November 2013 Order. Ultimately, these modifications did not alter the outcome of the test, so the HTP project is still mitigated.

Although the outcome of the BSM determination for the HTP project was unaffected by the use of actual financing costs, the practice of using a cost of equity that is not based on an objective methodology such as CAPM raises several concerns. First, developers may have strong incentives to submit a biased cost of equity in future determinations in order to avoid mitigation. Second, even if not intentionally biased, a developer's method of assessing its own cost of equity may not provide an apples-to-apples comparison with the cost of equity derived for the purposes of setting the ICAP demand curves. For future BSM determinations, it will be important for the NYISO to develop more objective analytical methods for evaluating the cost of equity submitted by the developer when it is different from that of the Demand Curve unit.